SECTION 2 – ENERGY MARKET, PART 1

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first six months of 2009, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2009.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

Overview

Market Structure

- **Supply.** During the April through June 2009 quarter, the PJM Energy Market received an hourly average of 153,310 MW in supply offers including hydroelectric generation.[3] The second quarter 2009 average supply offers were 2,149 MW lower than the second quarter 2008 average supply of 155,459 MW.

- **Demand.** The PJM system peak load in the second quarter 2009 was 116,732 MW in the hour ended 1700 EPT on June 25, 2009, while the PJM peak load in the second quarter 2008 was 130,100 in the hour ended 1700 on June 9, 2008.[4] The 2009 second quarter peak load was 13,368 MW, or 11.5 percent, lower than the second quarter 2008 peak load.

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.

1 Analysis of the first six months of 2009 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2008 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective August 1, 2008).

3 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

4 For the purpose of *2009 Quarterly State of the Market Report for PJM: January through June*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See *2008 State of the Market Report for PJM*, Appendix M, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in January through June 2009. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours were 0.2 percent of all hours in the first six months of 2009, the same level as 2008. In the Real-Time Energy Market offer-capped unit hours fell from 1.0 percent in 2008 to 0.5 percent of all hours in the first six months of 2009.

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 50 or more hours during the first two quarters of calendar year 2009. During the first two quarters of 2009 (January 1, 2009 through June 30, 2009), the PSEG, AP, AEP, PENELEC, Dominion, AECO, DLCO, ComEd, PECO and BGE Control Zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to ensure that owners are not subject to offer capping when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

Market Conduct

- **Price-Cost Markup.** The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. A positive markup by marginal units will result in a difference between the observed market price and the competitive market price. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[5] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[6] In the real time market, the average markup index from January to June 2009 was -0.07 with a monthly average maximum of -0.04 in January and a monthly average minimum of -0.1 in April. In the day ahead market, the average markup index from January to June 2009 was 0.0036 with a monthly average maximum of 0.02 in February and a minimum of -0.02 in April. The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior.

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP was $-3.10 per MWh, or -7.3 percent. The markup was

5 A marginal unit's offer price does not always correspond to the LMP at the unit's bus. As a general matter the LMP at a bus is equal to the unit's offer. However in practice, actual, security-constrained dispatch can create conditions where the LMP at a marginal unit bus does not correspond to the unit's offer. The marginal unit's offer price and associated cost are used when calculating measures of participant behavior or conduct, like markup.

6 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

$-2.49 per MWh during peak hours and $-3.74 per MWh during off-peak hours.

The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$0.05 per MWh, or -0.1 percent. The markup was $0.84 per MWh during peak hours and -$1.01 per MWh during off-peak hours.

The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** On average, PJM real-time load decreased in the first six months of 2009 by 3.4 percent from the first six months of 2008, falling from 78,684 MW to 75,993 MW. PJM day-ahead load decreased in the first six months of 2009 by 7.1 percent from the first six months of 2008, falling from 95,485 MW to 88,688 MW.

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. For example, overall average prices subsume congestion (price differences at a point in time) and price differences over time.

  PJM Real-Time Energy Market prices decreased in the first six months of 2009 compared to the first six months of 2008. The system simple average LMP was 42.9 percent lower in the first six months of 2009 than in the first six months of 2008, $40.12 per MWh versus $70.19 per MWh. The load-weighted LMP was 43.2 percent lower in the first six months of 2009 than in the first six months of 2008, $42.48 per MWh versus $74.77 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 6.4 percent lower in the first six months of 2009 than the load-weighted, average LMP in the first six months of 2008, $70.00 per MWh compared to $74.77 per MWh. Fuel costs and lower loads in the first half of 2009 contributed to downward pressure on LMP.

  PJM Day-Ahead Energy Market prices decreased in the first six months of 2009 compared to the first six months of 2008. The system simple average LMP was 42.9 percent lower in the first six months of 2009 than in the first six months of 2008, $40.01 per MWh versus $70.12 per MWh. The load-weighted LMP was 42.7 percent lower in the first six months of 2009 than in the first six months of 2008, $42.21 per MWh versus $73.71 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a single PJM parent company that serves load, its load can be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In the first six months of 2009, 13.4 percent of real-time load was supplied by bilateral contracts, 16.4 percent by spot market purchases and 70.2 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply decreased by 3.7 percentage points; and reliance on self-supply increased by 5.0 percentage points in January through June 2009.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. PJM wholesale market, demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. The current approach can and has resulted in payments when the customer has taken no action to respond to market prices. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

  Total demand-side response resources available in PJM on January 16, 2009 (the peak day in January through June 2009), were 4,498.2 MW eligible for capacity credits and 1,957.8 MW eligible for energy payments from the Emergency Load-Response Program and 3,311.0 MW from the Economic Load-Response Program.

Participation in the Economic Load-Response Program, in terms of settlement days submitted and active customers, has decreased significantly in the first six months of 2009 compared to the same period in 2008, resulting from a combination of program verification improvements implemented in 2008, and lower price levels across PJM in 2009. Participation in the Load Management (LM) Program has increased significantly, both in Demand Response offering into RPM Auctions and ILR available in delivery year 2009/2010.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the first six months of 2009, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply decreased by about 2,149 MW when comparing the second quarter of 2009 to the second quarter of 2008 while aggregate peak load decreased by 13,368 MW, modifying the general supply demand balance from 2008 with a corresponding impact on peak Energy Market prices. Overall load was also lower than in second quarter 2008. Market concentration levels remained moderate and average markup was negative. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to scarcity conditions. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests.

The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

Energy Market results for the first six months of 2009 generally reflected supply-demand fundamentals. Lower prices in the Energy Market were the result of lower fuel costs and of lower demand. PJM Real-Time, load-weighted, average LMP for the first six months of 2009 was 43.2 percent lower than the load-weighted, average LMP for the first six months of 2008. The real-time, fuel-cost-adjusted, load-weighted, average LMP in the first six months of 2009 was only 6.4 percent lower than the load-weighted LMP in the first six months of 2008. In other words, if fuel costs for the first six months of 2009 had been the same as for the first six months of 2008, the 2009 load-weighted LMP would have been higher, $70.00 per MWh and 6.4 percent lower than the first half of 2008, instead of the observed $42.48 per

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

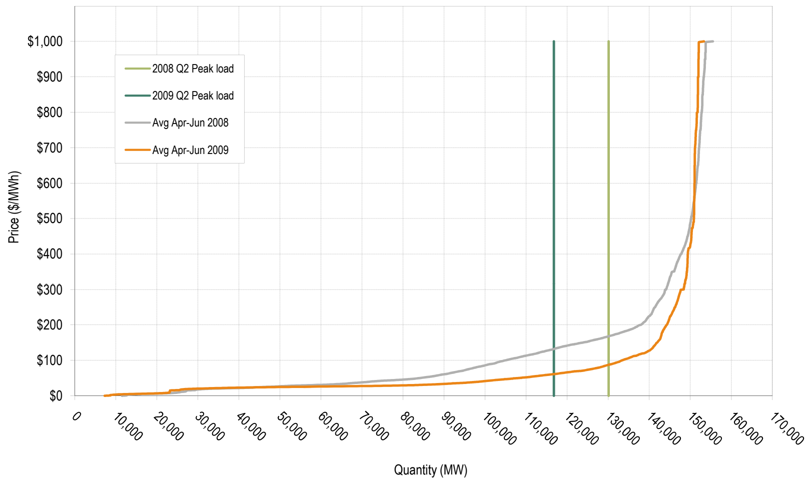
MWh. Lower fuel prices in 2009 resulted in lower prices in 2009 than would have occurred if fuel prices had remained at 2008 levels.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2009.

Market Structure

Supply

Figure 2-1 Average PJM aggregate supply curves: April through June 2008 and 2009 (See 2008 SOM, Figure 2-1)

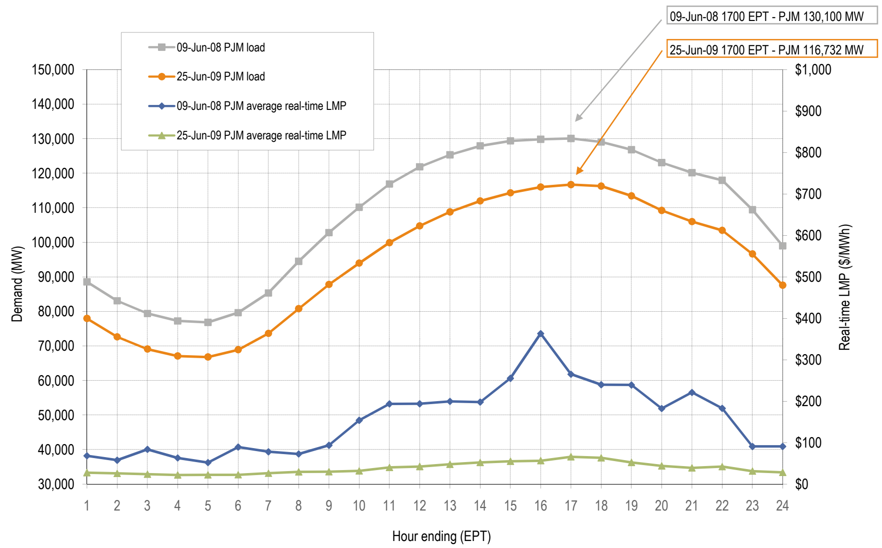


Demand

Table 2-1 Actual PJM footprint quarter 2 peak loads: 2005 to 2009 (See 2008 SOM, Table 2-2)

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
2005	28-Jun-05	1600	124,052	NA
2006	30-May-06	1700	121,165	(2,887)
2007	27-Jun-07	1600	130,971	9,806
2008	9-Jun-08	1700	130,100	(871)
2009	25-Jun-09	1700	116,732	(13,368)

Figure 2-2 PJM quarter 2 peak-load comparison: Thursday, June 25, 2009, and Monday, June 9, 2008 (See 2008 SOM, Figure 2-2)



Market Concentration

PJM HHI Results

Table 2-2 PJM hourly Energy Market HHI: January through June 2009 (See 2008 SOM, Table 2-3)

	Hourly Market HHI
Average	1260
Minimum	1044
Maximum	1628
Highest market share (One hour)	32%
Highest market share (All hours)	23%
# Hours	4343
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Local Market Structure and Offer Capping

Table 2-3 Annual offer-capping statistics: Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-5)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2005	1.8%	0.4%	0.2%	0.1%
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.5%	0.2%	0.2%	0.1%

Table 2-4 Offer-capped unit statistics: January through June 2009 (See 2008 SOM, Table 2-6)

	2009 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	3	25
80% and < 90%	0	0	0	0	0	7
75% and < 80%	0	0	0	0	0	12
70% and < 75%	0	0	0	0	0	10
60% and < 70%	0	0	0	0	1	17
50% and < 60%	0	0	0	0	0	13
25% and < 50%	0	0	0	0	0	31
10% and < 25%	0	0	0	1	1	29

Local Market Structure

Table 2-5 Three pivotal supplier results summary for regional constraints: January 1, 2009, through June 30, 2009[7] (See 2008 SOM, Table 2-7)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	581	561	97%	44	8%
	Off Peak	133	127	95%	16	12%
AP South	Peak	856	492	57%	538	63%
	Off Peak	495	279	56%	325	66%
Bedington - Black Oak	Peak	243	216	89%	117	48%
	Off Peak	110	84	76%	41	37%
Kammer	Peak	1,974	1,843	93%	307	16%
	Off Peak	2,339	2,062	88%	545	23%
West	Peak	231	225	97%	22	10%
	Off Peak	59	59	100%	0	0%

7 The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Table 2-6 Three pivotal supplier test details for regional constraints: January 1, 2009, through June 30, 2009[8] (See 2008 SOM, Table 2-8)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	61	346	19	18	1
	Off Peak	57	307	17	16	1
AP South	Peak	94	286	12	6	6
	Off Peak	103	309	11	5	6
Bedington - Black Oak	Peak	67	193	12	9	3
	Off Peak	57	214	13	9	4
Kammer	Peak	49	247	20	18	2
	Off Peak	51	234	16	14	2
West	Peak	132	592	20	20	1
	Off Peak	121	738	18	18	0

Table 2-7 Three pivotal supplier results summary for the East and Central interfaces: January 1, 2009, through June 30, 2009[9] (See 2008 SOM, Table 2-13)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Central	Peak	17	17	100%	0	0%
	Off Peak	9	9	100%	0	0%
East	Peak	0	NA	NA	NA	NA
	Off Peak	0	NA	NA	NA	NA

Table 2-8 Three pivotal supplier test details for the East and Central interfaces: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-15)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	61	565	19	19	0
	Off Peak	84	884	19	19	0
East	Peak	NA	NA	NA	NA	NA
	Off Peak	NA	NA	NA	NA	NA

Table 2-9 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-17)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	292	8	3%	288	99%
	Off Peak	122	5	4%	121	99%
Brunswick - Edison	Peak	226	6	3%	226	100%
	Off Peak	84	0	0%	84	100%
Cedar Grove - Roseland	Peak	216	33	15%	199	92%
	Off Peak	12	0	0%	12	100%
Plainsboro - Trenton	Peak	592	0	0%	592	100%
	Off Peak	13	0	0%	13	100%

8 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

9 The East Interface constraint did not occur from January 1, 2009 through June 30, 2009. The Central Interface constraint occurred for eight hours from January 1, 2009 through June 30, 2009.

Table 2-10 Three pivotal supplier test details for constraints located in the PSEG Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-18)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	13	36	3	0	3
	Off Peak	10	40	3	0	3
Brunswick - Edison	Peak	8	89	1	0	1
	Off Peak	6	65	1	0	1
Cedar Grove - Roseland	Peak	40	156	8	1	7
	Off Peak	27	182	8	0	8
Plainsboro - Trenton	Peak	9	122	1	0	1
	Off Peak	7	141	1	0	1

Table 2-11 Three pivotal supplier results summary for constraints located in the AP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-19)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bedington	Peak	569	125	22%	569	100%
	Off Peak	333	11	3%	333	100%
Sammis - Wylie Ridge	Peak	128	86	67%	53	41%
	Off Peak	441	324	73%	204	46%
Tiltonsville - Windsor	Peak	918	1	0%	917	100%
	Off Peak	217	0	0%	217	100%
Wylie Ridge	Peak	695	577	83%	182	26%
	Off Peak	945	653	69%	378	40%

Table 2-12 Three pivotal supplier test details for constraints located in the AP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-20)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	40	4	3	0	2
	Off Peak	38	4	3	0	3
Sammis - Wylie Ridge	Peak	48	116	17	11	6
	Off Peak	54	130	17	11	6
Tiltonsville - Windsor	Peak	12	6	2	0	2
	Off Peak	7	7	2	0	2
Wylie Ridge	Peak	36	147	17	15	2
	Off Peak	37	141	14	12	2

Table 2-13 Three pivotal supplier results summary for constraints located in the AEP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-21)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cloverdale - Lexington	Peak	264	146	55%	178	67%
	Off Peak	930	528	57%	602	65%
Kammer - Ormet	Peak	1,439	28	2%	1,411	98%
	Off Peak	1,965	0	0%	1,965	100%
Kanawha River - Kincaid	Peak	318	0	0%	318	100%
	Off Peak	240	0	0%	240	100%
Poston - Postel Tap	Peak	211	0	0%	211	100%
	Off Peak	0	NA	NA	NA	NA
Ruth - Turner	Peak	1,263	0	0%	1,263	100%
	Off Peak	1,470	0	0%	1,470	100%

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Table 2-14 Three pivotal supplier test details for constraints located in the AEP Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-22)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cloverdale - Lexington	Peak	75	223	16	8	8
	Off Peak	69	201	14	7	7
Kammer - Ormet	Peak	18	21	1	0	1
	Off Peak	22	31	1	0	1
Kanawha River - Kincaid	Peak	12	4	1	0	1
	Off Peak	9	5	1	0	1
Poston - Postel Tap	Peak	6	14	1	0	1
	Off Peak	NA	NA	NA	NA	NA
Ruth - Turner	Peak	19	3	1	0	1
	Off Peak	20	3	1	0	1

Table 2-15 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-25)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Homer City - Shelocta	Peak	302	20	7%	293	97%
	Off Peak	82	0	0%	82	100%

Table 2-16 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-26)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Homer City - Shelocta	Peak	29	67	5	0	5
	Off Peak	47	57	6	0	6

Table 2-17 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-27)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Beechwood - Kerr Dam	Peak	540	0	0%	540	100%
	Off Peak	117	0	0%	117	100%

Table 2-18 Three pivotal supplier test details for constraints located in the Dominion Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-28)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	4	4	1	0	1
	Off Peak	4	2	1	0	1

Table 2-19 Three pivotal supplier results summary for constraints located in the AECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-31)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Absecon - Lewis	Peak	61	0	0%	61	100%
	Off Peak	16	0	0%	16	100%

Table 2-20 Three pivotal supplier test details for constraints located in the AECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-32)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Absecon - Lewis	Peak	8	19	1	0	1
	Off Peak	7	27	1	0	1

Table 2-21 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-33)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Logans Ferry - Universal	Peak	963	0	0%	963	100%
	Off Peak	197	0	0%	197	100%

Table 2-22 Three pivotal supplier test details for constraints located in the DLCO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-34)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Logans Ferry - Universal	Peak	7	42	1	0	1
	Off Peak	6	37	1	0	1

Table 2-23 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-35)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Crete - East Frankfurt	Peak	62	16	26%	59	95%
	Off Peak	897	68	8%	876	98%
Electric Jct - Nelson	Peak	175	5	3%	174	99%
	Off Peak	267	1	0%	267	100%
Electric Junction - Aurora	Peak	27	0	0%	27	100%
	Off Peak	4	0	0%	4	100%
Pleasant Valley - Belvidere	Peak	334	0	0%	334	100%
	Off Peak	671	0	0%	671	100%

Table 2-24 Three pivotal supplier test details for constraints located in the ComEd Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-36)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Crete - East Frankfurt	Peak	34	89	5	1	4
	Off Peak	37	49	4	0	4
Electric Jct - Nelson	Peak	28	16	3	0	3
	Off Peak	37	9	2	0	2
Electric Junction - Aurora	Peak	8	15	2	0	2
	Off Peak	14	2	1	0	1
Pleasant Valley - Belvidere	Peak	12	1	1	0	1
	Off Peak	13	0	1	0	1

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Table 2-25 Three pivotal supplier results summary for constraints located in the PECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-37)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Buckingham - Pleasant Valley	Peak	200	81	41%	147	74%
	Off Peak	41	28	68%	19	46%

Table 2-26 Three pivotal supplier test details for constraints located in the PECO Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-38)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Buckingham - Pleasant Valley	Peak	12	41	7	3	4
	Off Peak	8	47	10	6	4

Table 2-27 Three pivotal supplier results summary for constraints located in the BGE Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-39)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Graceton - Raphael Road	Peak	331	307	93%	44	13%
	Off Peak	105	86	82%	36	34%

Table 2-28 Three pivotal supplier test details for constraints located in the BGE Control Zone: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-40)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Raphael Road	Peak	30	123	19	18	1
	Off Peak	39	114	19	15	4

Market Performance: Markup

Real-Time Markup

Table 2-29 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): January through June 2009 (See 2007 SOM, Table 2-31)

Company	Percent of Price
1	16%
2	14%
3	9%
4	8%
5	8%
6	7%
7	6%
8	4%
9	3%
Other (46 companies)	25%

Table 2-30 Type of fuel used (By real-time marginal units): January through June 2009 (See 2007 SOM, Table 2-32)

Fuel Type	2009
Coal	75%
Natural Gas	20%
Petroleum	3%
Landfill Gas	1%
Interface	1%
Misc	0%

Figure 2-3 Real-time, LMP contribution and load-weighted, unit markup index: January through June 2009 (See 2007 SOM, Figure 2-4)

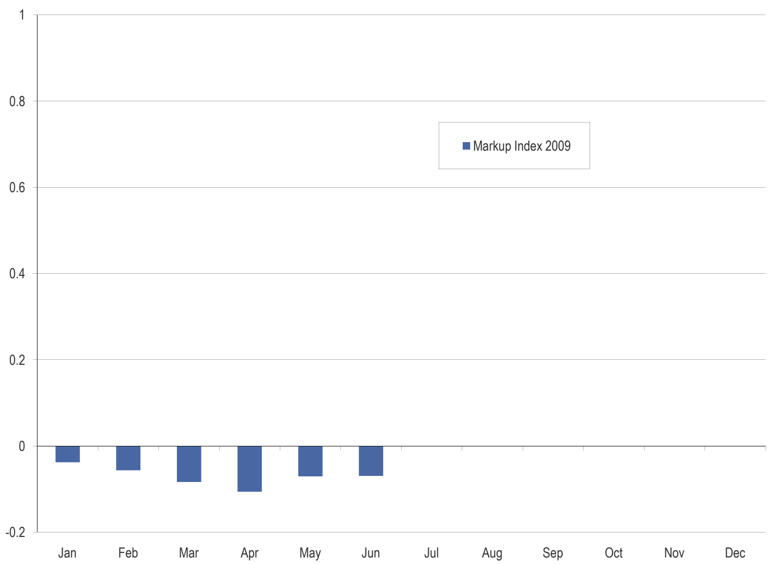


Table 2-31 Average, real-time marginal unit markup index (By price category): January through June 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.11)	($3.65)
$25 to $50	(0.11)	($5.50)
$50 to $75	(0.03)	($2.87)
$75 to $100	0.03	$2.10
$100 to $125	0.07	$6.08
$125 to $150	0.07	$6.82
> $150	0.05	$9.94

Table 2-32 Monthly markup components of load-weighted LMP: January through June 2009 (See 2007 SOM, Table 2-35)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.53)	($0.48)	($2.52)
Feb	($1.97)	($1.65)	($2.31)
Mar	($4.24)	($4.73)	($3.73)
Apr	($4.78)	($3.78)	($5.96)
May	($3.23)	($2.75)	($3.68)
Jun	($3.33)	($1.99)	($4.98)
2009 (Jan - Jun)	($3.10)	($2.49)	($3.74)

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Table 2-33 Average real-time zonal markup component: January through June 2009 (See 2007 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($3.09)	($2.77)	($3.42)
AEP	($3.62)	($2.80)	($4.46)
AP	($2.65)	($1.89)	($3.45)
BGE	($2.47)	($1.78)	($3.18)
ComEd	($3.90)	($3.18)	($4.69)
DAY	($4.01)	($3.15)	($4.94)
DLCO	($4.10)	($3.17)	($5.10)
Dominion	($2.24)	($1.66)	($2.84)
DPL	($2.66)	($2.27)	($3.06)
JCPL	($2.90)	($2.54)	($3.30)
Met-Ed	($2.78)	($2.47)	($3.12)
PECO	($3.01)	($2.76)	($3.28)
PENELEC	($3.21)	($2.75)	($3.71)
Pepco	($2.41)	($1.84)	($3.02)
PPL	($2.87)	($2.60)	($3.15)
PSEG	($2.98)	($2.52)	($3.49)
RECO	($2.86)	($2.41)	($3.38)

Table 2-34 Average real-time markup component (By price category): January through June 2009 (See 2008 SOM, Table 2-41)

	Average Markup Component	Frequency
Below $20	($2.62)	3.6%
$20 to $40	($5.66)	61.0%
$40 to $60	($2.74)	24.5%
$60 to $80	$1.21	6.5%
$80 to $100	$8.23	2.6%
$100 to $120	$11.50	0.8%
$120 to $140	$40.38	0.5%
$140 to $160	$12.72	0.2%
Above $160	$52.56	0.2%

Day-Ahead Markup

Table 2-35 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): January through June 2009 (See 2007 SOM, Table 2-31)

Company	Percent of Price
1	35%
2	8%
3	5%
4	5%
5	5%
6	4%
7	3%
8	3%
9	3%
Other (111 companies)	30%

Table 2-36 Day-ahead marginal resources by type/fuel: January through June 2009 (See 2007 SOM, Table 2-32)

Fuel Type	2009
Transaction	36%
DEC	29%
INC	17%
Coal	13%
Natural gas	3%
Price sensitive demand	1%
Petroleum	0%
Wind	0%
Misc	0%
Landfill gas	0%

Figure 2-4 Day-ahead, LMP contribution and load-weighted unit markup index: January through June 2009 (See 2007 SOM, Figure 2-4)

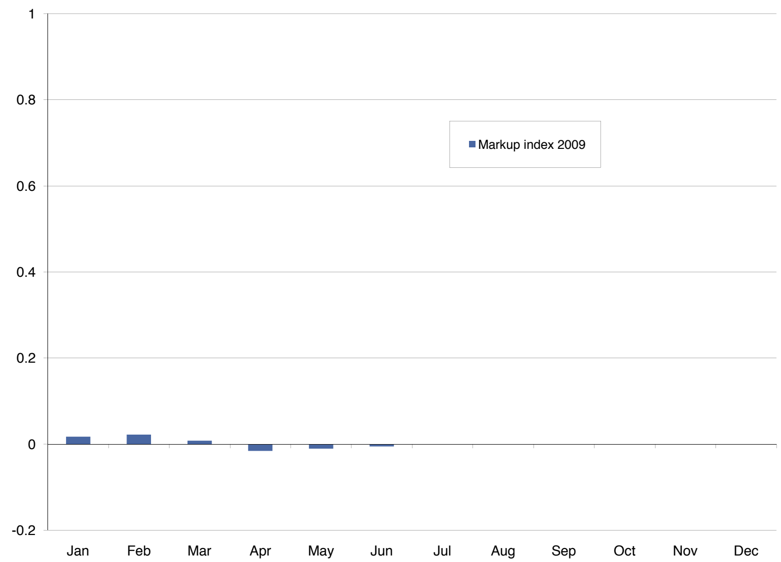


Table 2-37 Average, day-ahead marginal unit markup index (By price category): January through June 2009 (See 2007 SOM, Table 2-34)

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.05)	($2.25)
$25 to $50	0.05	$1.12
$50 to $75	0.08	$4.79
$75 to $100	0.09	$7.98
$100 to $125	0.28	$31.16
$125 to $150	(0.04)	($8.16)
> $150	0.00	$0.00

Table 2-38 Monthly markup components of day-ahead, load-weighted LMP: January through June 2009 (See 2007 SOM, Table 2-35)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$0.89	$1.62	$0.20
Feb	$0.76	$2.18	($0.75)
Mar	$0.16	$0.91	($0.65)
Apr	($0.97)	($0.33)	($1.72)
May	($0.62)	$0.07	($1.28)
Jun	($0.83)	$0.39	($2.37)
2009 (Jan - Jun)	($0.05)	$0.84	($1.01)

Table 2-39 Day-ahead, average, zonal markup component: January through June 2009 (See 2007 SOM, Table 2-36)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$0.20	$0.98	($0.66)
AEP	($0.50)	$0.67	($1.72)
AP	$0.79	$1.68	($0.13)
BGE	$0.13	$1.12	($0.93)
ComEd	($0.08)	$0.75	($0.94)
DAY	($0.60)	$0.59	($1.92)
DLCO	($0.56)	$0.62	($1.83)
Dominion	($0.45)	$0.38	($1.29)
DPL	$0.24	$0.99	($0.53)
JCPL	$0.34	$1.13	($0.58)
Met-Ed	$0.30	$1.07	($0.54)
PECO	$0.21	$1.02	($0.65)
PENELEC	$0.41	$1.18	($0.49)
Pepco	($0.19)	$0.69	($1.18)
PPL	$0.26	$0.93	($0.47)
PSEG	$0.12	$0.82	($0.68)
RECO	$0.20	$0.89	($0.64)

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Table 2-40 Average, day-ahead markup (By price category): January through June 2009 (See 2007 SOM, Table 2-37)

	Average Markup Component	Frequency
Below $20	($0.51)	4%
$20 to $40	($1.41)	56%
$40 to $60	$1.16	30%
$60 to $80	$1.50	7%
$80 to $100	$2.75	2%
$100 to $120	$4.26	1%
$120 to $140	$1.43	0%
Above $160	$0.00	0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

Table 2-41 Frequently mitigated units and associated units (By month): January through June 2009 (See 2008 SOM, Table 2-42)

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	26	56	55	137
February	46	46	36	128
March	31	48	54	133
April	33	41	63	137
May	32	43	61	136
June	40	42	62	144

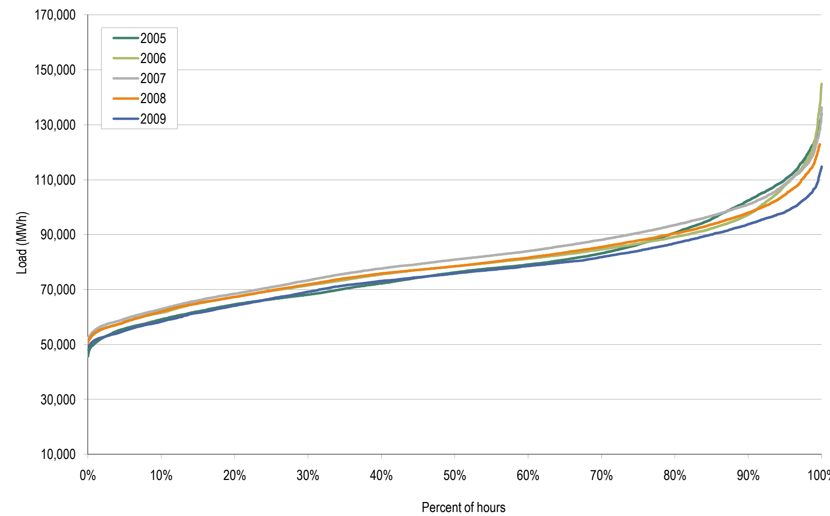
Market Performance: Load and LMP

Load

Real-Time Load

PJM Real-Time Load Duration

Figure 2-5 PJM real-time load duration curves: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-4)



PJM Real-Time, Annual Average Load

Table 2-42 PJM real-time average load: Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-44)

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	30,113	30,170	5,529	NA	NA	NA
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	75,993	75,847	12,898	(4.4%)	(3.4%)	(6.2%)

PJM Real-Time, Monthly Average Load

Figure 2-6 PJM real-time average load: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-5)

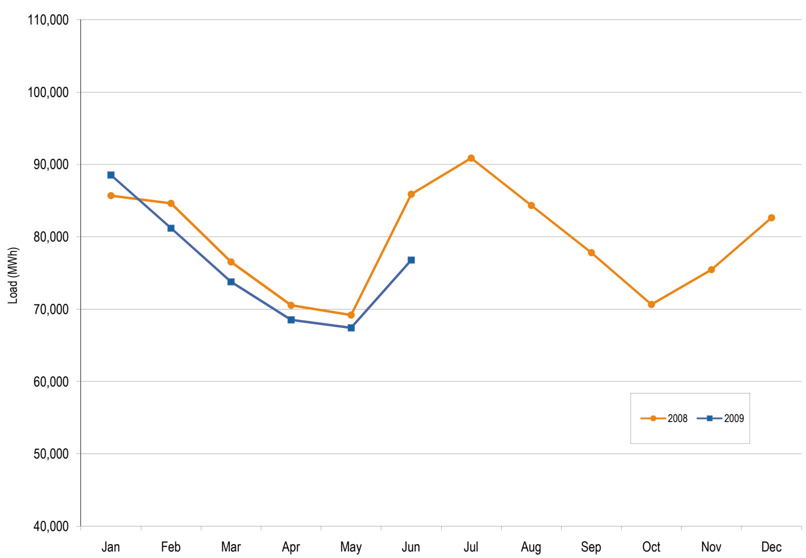


Table 2-43 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009 (See 2008 SOM, Table 2-45)

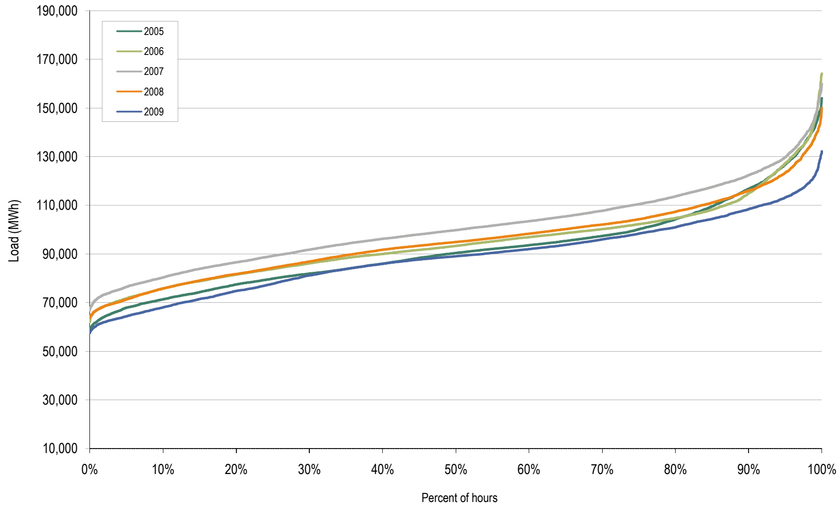
	2008			2009			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	54.94	70.16	81.30	52.53	67.86	77.88	(4.4%)	(3.3%)	(4.2%)
Jul	62.00	72.25	80.34						
Aug	59.89	69.70	78.62						

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Day-Ahead Load

PJM Day-Ahead Load Duration

Figure 2-7 PJM day-ahead load duration curves: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-6)



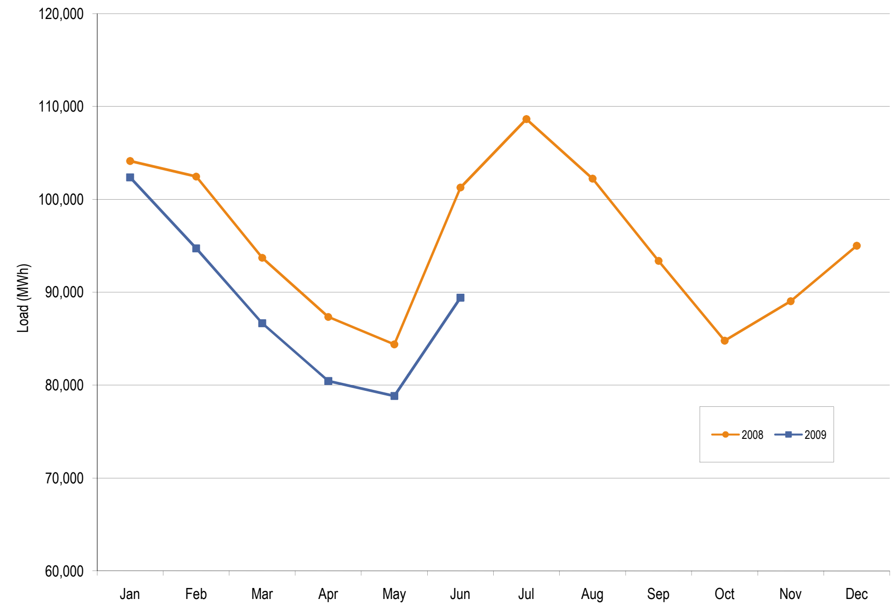
PJM Day-Ahead, Annual Average Load

Table 2-44 PJM day-ahead average load: Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-46)

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	92,002	90,424	17,381	NA	NA	NA
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,688	89,066	14,650	(7.2%)	(6.1%)	(5.1%)

PJM Day-Ahead, Monthly Average Load

Figure 2-8 PJM day-ahead average load: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-7)

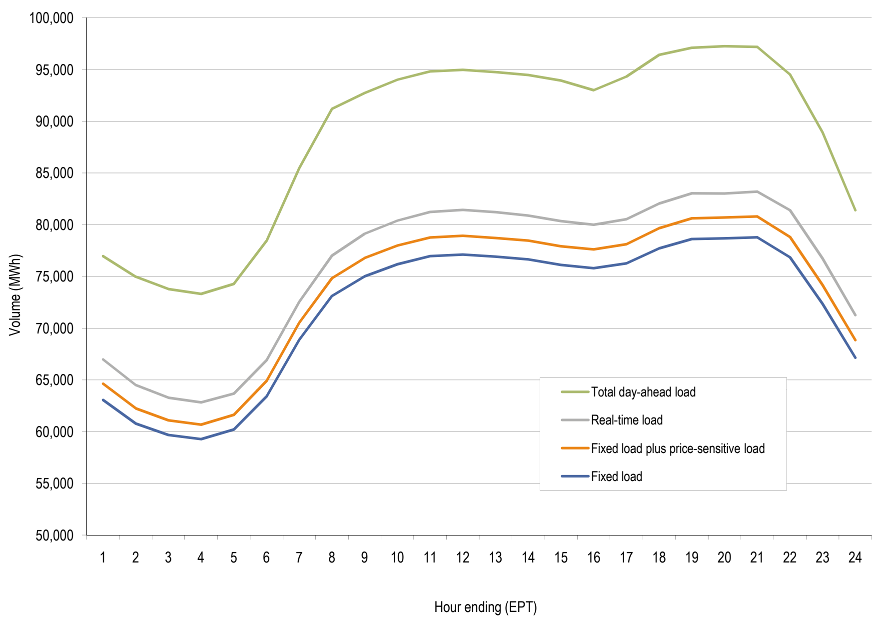


Real-Time and Day-Ahead Load

Table 2-45 Cleared day-ahead and real-time load (MWh): January through June 2009 (See 2008 SOM, Table 2-47)

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	71,903	1,742	15,043	88,688	75,993	12,695	(2,348)
Median	71,635	1,739	15,310	89,066	75,847	13,219	(2,091)
Standard deviation	12,110	435	2,554	14,650	12,898	1,752	(802)

Figure 2-9 Day-ahead and real-time loads (Average hourly volumes): January through June 2009 (See 2008 SOM, Figure 2-8)

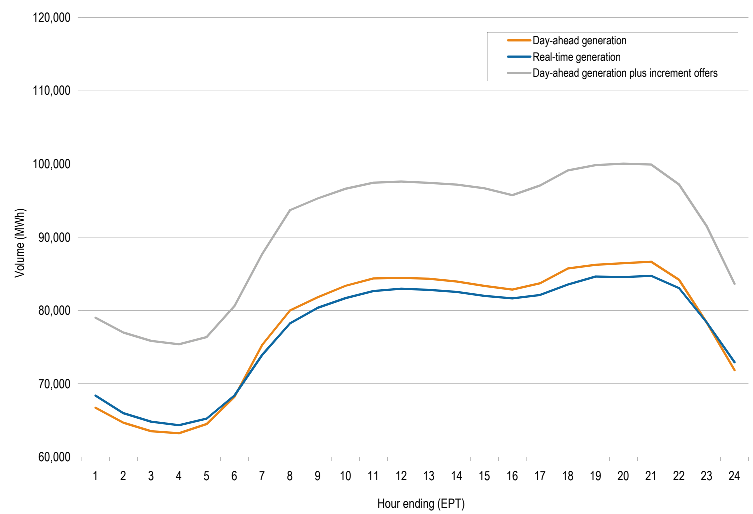


Real-Time and Day-Ahead Generation

Table 2-46 Day-ahead and real-time generation (MWh): January through June 2009 (See 2008 SOM, Table 2-48)

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	78,259	12,907	91,166	77,508	751	13,658
Median	78,909	12,781	91,595	77,626	1,283	13,970
Standard deviation	14,195	1,673	15,055	12,961	1,233	2,093

Figure 2-10 Day-ahead and real-time generation (Average hourly volumes): January through June 2009 (See 2008 SOM, Figure 2-9)



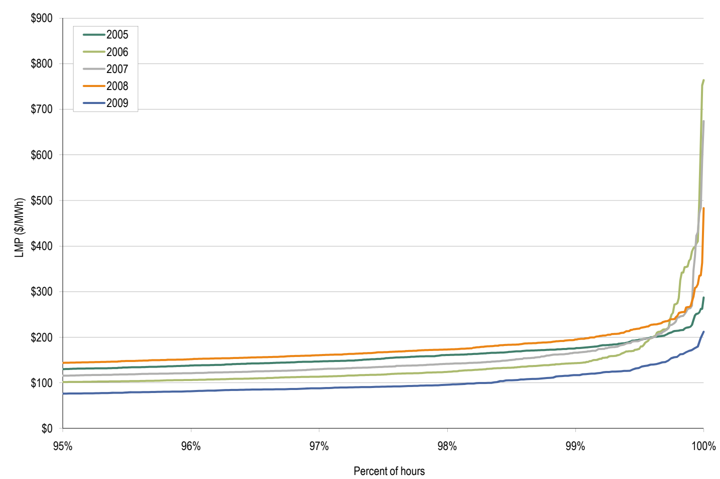
Locational Marginal Price (LMP)

Real-Time LMP

Real-Time Average LMP

PJM Real-Time LMP Duration

Figure 2-11 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-10)



© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

PJM Real-Time, Annual Average LMP

Table 2-47 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-49)

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$28.14	$19.11	$25.69	NA	NA	NA
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$40.12	$35.42	$19.30	(39.6%)	(36.2%)	(50.0%)

Zonal Real-Time, Annual Average LMP

Table 2-48 Zonal real-time, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-50)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$84.92	$44.59	($40.33)	(47.5%)
AEP	$56.20	$36.37	($19.83)	(35.3%)
AP	$69.61	$41.77	($27.84)	(40.0%)
BGE	$84.14	$45.22	($38.92)	(46.3%)
ComEd	$52.81	$30.28	($22.53)	(42.7%)
DAY	$56.66	$35.90	($20.76)	(36.6%)
DLCO	$52.57	$34.49	($18.08)	(34.4%)
Dominion	$78.58	$43.53	($35.05)	(44.6%)
DPL	$81.59	$45.20	($36.39)	(44.6%)
JCPL	$86.58	$44.92	($41.66)	(48.1%)
Met-Ed	$79.58	$43.73	($35.85)	(45.0%)
PECO	$78.86	$43.63	($35.23)	(44.7%)
PENELEC	$67.94	$40.06	($27.88)	(41.0%)
Pepco	$84.33	$44.77	($39.56)	(46.9%)
PPL	$78.47	$43.14	($35.34)	(45.0%)
PSEG	$85.48	$45.44	($40.04)	(46.8%)
RECO	$84.33	$44.22	($40.11)	(47.6%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-49 Jurisdiction real-time, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-51)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$80.69	$44.87	($35.83)	(44.4%)
Illinois	$52.81	$30.28	($22.53)	(42.7%)
Indiana	$56.03	$35.71	($20.33)	(36.3%)
Kentucky	$56.50	$36.25	($20.25)	(35.8%)
Maryland	$83.80	$45.20	($38.61)	(46.1%)
Michigan	$56.95	$37.07	($19.88)	(34.9%)
New Jersey	$85.75	$45.16	($40.59)	(47.3%)
North Carolina	$73.52	$42.45	($31.08)	(42.3%)
Ohio	$55.67	$35.69	($19.98)	(35.9%)
Pennsylvania	$73.14	$41.88	($31.27)	(42.7%)
Tennessee	$56.75	$36.34	($20.41)	(36.0%)
Virginia	$76.00	$42.77	($33.23)	(43.7%)
West Virginia	$57.92	$37.62	($20.30)	(35.0%)
District of Columbia	$84.32	$44.92	($39.40)	(46.7%)

Hub Real-Time, Annual Average LMP

Table 2-50 Hub real-time, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-52)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AEP Gen Hub	$53.04	$34.21	($18.83)	(35.5%)
AEP-DAY Hub	$55.92	$35.87	($20.04)	(35.8%)
Chicago Gen Hub	$52.10	$29.44	($22.66)	(43.5%)
Chicago Hub	$52.86	$30.49	($22.37)	(42.3%)
Dominion Hub	$76.02	$42.82	($33.19)	(43.7%)
Eastern Hub	$81.31	$45.06	($36.24)	(44.6%)
N Illinois Hub	$52.37	$30.07	($22.30)	(42.6%)
New Jersey Hub	$85.45	$45.11	($40.34)	(47.2%)
Ohio Hub	$56.03	$35.84	($20.19)	(36.0%)
West Interface Hub	$61.55	$37.20	($24.35)	(39.6%)
Western Hub	$72.09	$41.40	($30.69)	(42.6%)

Real-Time, Load-Weighted, Average LMP

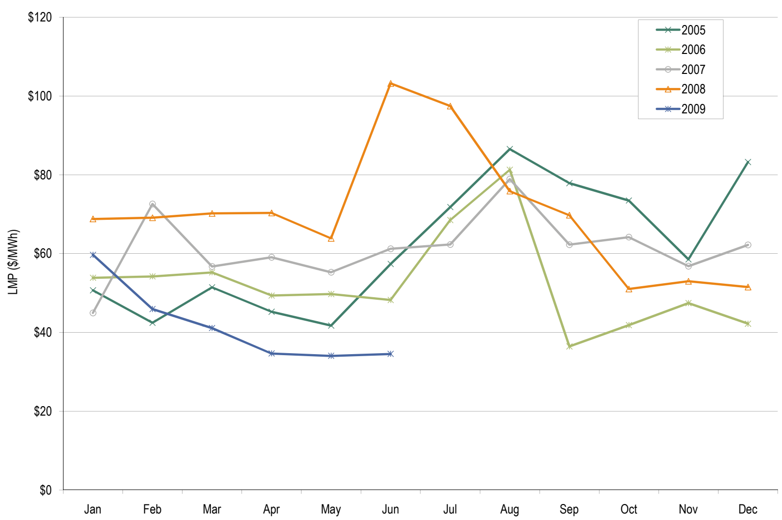
PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-51 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-53)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$30.72	$20.51	$28.38	NA	NA	NA
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$42.48	$36.95	$20.61	(40.3%)	(37.9%)	(49.7%)

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 2-12 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-11)



Zonal Real-Time, Annual, Load-Weighted, Average LMP

Table 2-52 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-54)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$93.41	$46.77	($46.64)	(49.9%)
AEP	$59.26	$38.30	($20.96)	(35.4%)
AP	$73.85	$44.59	($29.26)	(39.6%)
BGE	$91.31	$48.39	($42.92)	(47.0%)
ComEd	$56.35	$32.25	($24.10)	(42.8%)
DAY	$60.47	$37.77	($22.70)	(37.5%)
DLCO	$55.68	$35.62	($20.06)	(36.0%)
Dominion	$85.94	$46.89	($39.04)	(45.4%)
DPL	$87.98	$48.77	($39.21)	(44.6%)
JCPL	$94.12	$47.50	($46.62)	(49.5%)
Met-Ed	$84.70	$46.64	($38.06)	(44.9%)
PECO	$84.40	$46.05	($38.35)	(45.4%)
PENELEC	$71.14	$42.08	($29.06)	(40.8%)
Pepco	$92.13	$47.69	($44.43)	(48.2%)
PPL	$83.20	$46.39	($36.81)	(44.2%)
PSEG	$91.71	$47.42	($44.29)	(48.3%)
RECO	$92.02	$46.29	($45.73)	(49.7%)

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Real-Time, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-53 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-55)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$86.35	$47.92	($38.43)	(44.5%)
Illinois	$56.35	$32.25	($24.10)	(42.8%)
Indiana	$58.65	$37.00	($21.65)	(36.9%)
Kentucky	$60.42	$39.03	($21.39)	(35.4%)
Maryland	$91.33	$48.71	($42.62)	(46.7%)
Michigan	$60.58	$38.50	($22.08)	(36.4%)
New Jersey	$92.65	$47.34	($45.31)	(48.9%)
North Carolina	$82.09	$45.76	($36.33)	(44.3%)
Ohio	$58.74	$37.35	($21.39)	(36.4%)
Pennsylvania	$77.42	$44.33	($33.10)	(42.7%)
Tennessee	$58.81	$38.96	($19.85)	(33.7%)
Virginia	$82.83	$46.18	($36.65)	(44.2%)
West Virginia	$60.97	$40.12	($20.85)	(34.2%)
District of Columbia	$90.78	$46.88	($43.90)	(48.4%)

Real-Time, Fuel-Cost-Adjusted, Load-Weighted LMP

Fuel Cost

Figure 2-13 Spot average fuel price comparison: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-12)

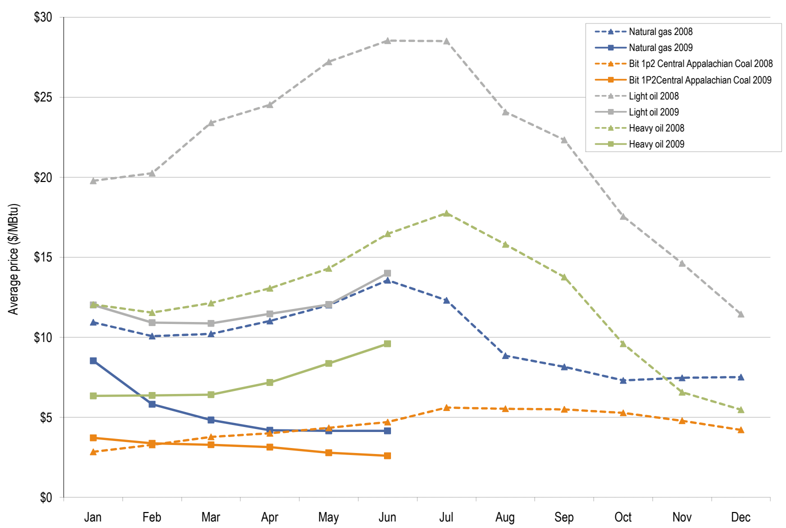


Figure 2-14 Spot average emission price comparison: Calendar years 2008 through June 2009 (See 2008 SOM, Figure 2-13)

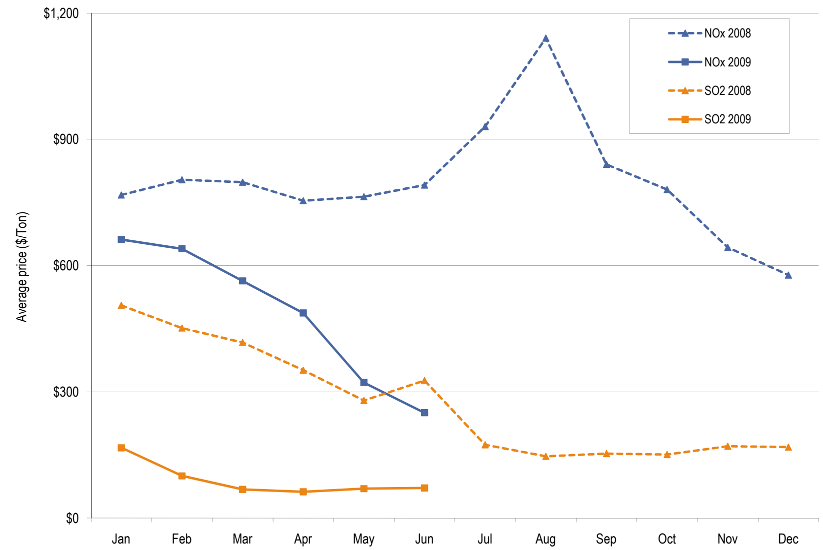


Table 2-54 PJM real-time, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): January through June 2009, year-over-year method (See 2008 SOM, Table 2-56)

	2008 (Jan - Jun) Load-Weighted LMP	2009 (Jan - Jun) Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$74.77	$70.00	(6.4%)

Components of Real-Time, Load-Weighted LMP

Table 2-55 Components of PJM annual, load-weighted, average LMP: January through June 2009 (See 2008 SOM, Table 2-57)

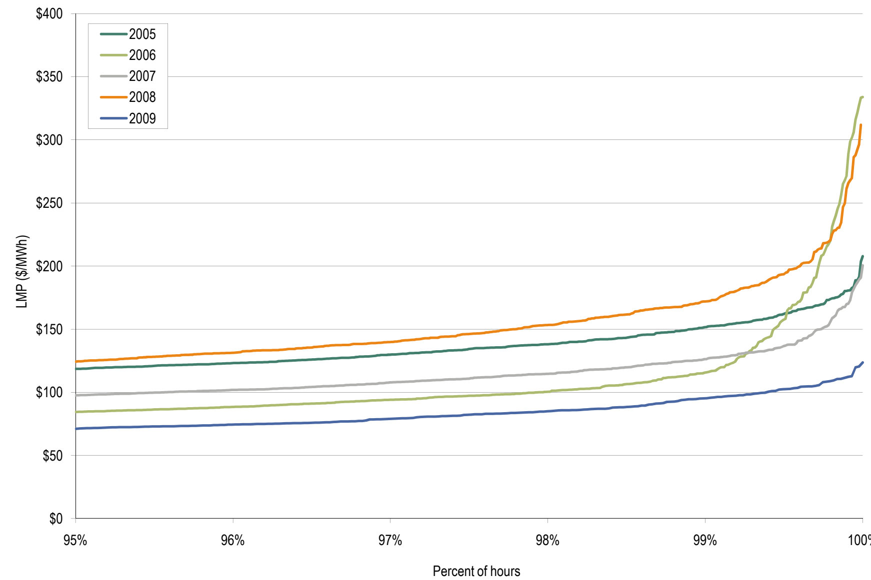
Element	Contribution to LMP	Percent
Coal	$25.49	60.0%
Gas	$14.92	35.1%
Oil	$1.34	3.2%
Uranium	$0.00	0.0%
Municipal Waste	$0.02	0.0%
FMU Adder	$0.23	0.5%
SO2	$0.94	2.2%
NOX	$0.22	0.5%
VOM	$2.96	7.0%
Markup	($3.10)	(7.3%)
Offline CT Adder	$0.07	0.2%
UDS Override Differential	($0.24)	(0.6%)
Dispatch Differential	($0.10)	(0.2%)
M2M Adder	($0.29)	(0.7%)
Flow violation Adjustment	($0.02)	(0.0%)
Unit LMP Differential	($0.00)	(0.0%)
NA	$0.04	0.1%
LMP	$42.48	100.0%

Day-Ahead LMP

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

Figure 2-15 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-14)



PJM Day-Ahead, Annual Average LMP

Table 2-56 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-61)

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	$57.89	$50.08	$30.04	NA	NA	NA
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$40.01	$37.46	$15.38	(39.5%)	(36.4%)	(50.2%)

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Zonal Day-Ahead, Annual Average LMP

Table 2-57 Zonal day-ahead, simple average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-62)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$83.43	$45.38	($38.05)	(45.6%)
AEP	$56.26	$36.19	($20.07)	(35.7%)
AP	$69.57	$41.11	($28.46)	(40.9%)
BGE	$85.34	$46.01	($39.32)	(46.1%)
ComEd	$53.80	$30.42	($23.38)	(43.4%)
DAY	$56.33	$35.34	($20.99)	(37.3%)
DLCO	$54.78	$34.04	($20.73)	(37.9%)
Dominion	$79.34	$44.17	($35.17)	(44.3%)
DPL	$82.19	$45.80	($36.39)	(44.3%)
JCPL	$87.60	$45.58	($42.02)	(48.0%)
Met-Ed	$80.83	$44.24	($36.58)	(45.3%)
PECO	$80.54	$44.67	($35.87)	(44.5%)
PENELEC	$70.22	$40.30	($29.92)	(42.6%)
Pepco	$86.25	$45.60	($40.64)	(47.1%)
PPL	$79.68	$43.82	($35.86)	(45.0%)
PSEG	$86.08	$46.27	($39.82)	(46.3%)
RECO	$84.51	$45.06	($39.45)	(46.7%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-58 Day-ahead, simple average LMP (Dollars per MWh) by jurisdiction: January through June 2008 and 2009 (See 2008 SOM, Table 2-63)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$81.25	$45.21	($36.04)	(44.4%)
Illinois	$53.80	$30.42	($23.38)	(43.4%)
Indiana	$56.39	$35.47	($20.92)	(37.1%)
Kentucky	$55.71	$35.95	($19.76)	(35.5%)
Maryland	$84.73	$45.89	($38.84)	(45.8%)
Michigan	$57.13	$36.78	($20.34)	(35.6%)
New Jersey	$86.24	$45.94	($40.30)	(46.7%)
North Carolina	$74.53	$43.03	($31.50)	(42.3%)
Ohio	$55.75	$35.29	($20.47)	(36.7%)
Pennsylvania	$74.70	$42.33	($32.37)	(43.3%)
Tennessee	$56.34	$36.51	($19.83)	(35.2%)
Virginia	$76.57	$43.40	($33.17)	(43.3%)
West Virginia	$57.46	$37.35	($20.11)	(35.0%)
District of Columbia	$85.92	$45.68	($40.24)	(46.8%)

Day-Ahead, Load-Weighted, Average LMP

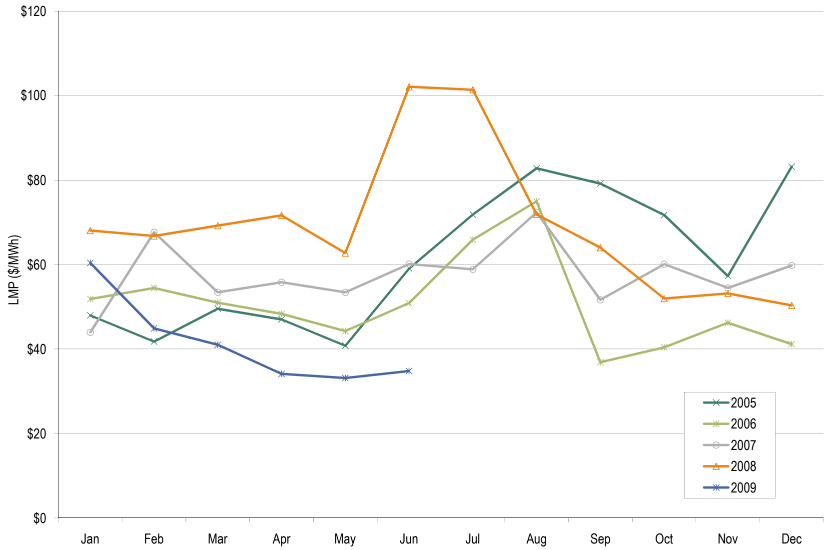
PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-59 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2005 through June 2009 (See 2008 SOM, Table 2-64)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2005	$62.50	$54.74	$31.72	NA	NA	NA
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$42.21	$38.83	$16.16	(39.9%)	(38.3%)	(51.2%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-16 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2005 through June 2009 (See 2008 SOM, Figure 2-15)



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-60 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-65)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
AECO	$90.78	$48.09	($42.69)	(47.0%)
AEP	$58.75	$37.95	($20.79)	(35.4%)
AP	$71.72	$43.83	($27.89)	(38.9%)
BGE	$91.96	$49.12	($42.84)	(46.6%)
ComEd	$56.09	$31.72	($24.37)	(43.4%)
DAY	$59.19	$36.99	($22.20)	(37.5%)
DLCO	$57.72	$35.10	($22.63)	(39.2%)
Dominion	$85.99	$47.39	($38.60)	(44.9%)
DPL	$88.22	$48.86	($39.36)	(44.6%)
JCPL	$94.29	$47.94	($46.35)	(49.2%)
Met-Ed	$84.63	$47.29	($37.34)	(44.1%)
PECO	$85.89	$47.08	($38.81)	(45.2%)
PENELEC	$72.09	$42.35	($29.75)	(41.3%)
Pepco	$90.58	$48.20	($42.38)	(46.8%)
PPL	$83.57	$46.72	($36.85)	(44.1%)
PSEG	$91.65	$48.45	($43.20)	(47.1%)
RECO	$91.10	$47.59	($43.52)	(47.8%)

Day-Ahead, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-61 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-66)

	2008 (Jan - Jun)	2009 (Jan - Jun)	Difference	Difference as Percent of 2008
Delaware	$87.13	$48.05	($39.08)	(44.9%)
Illinois	$56.09	$31.72	($24.37)	(43.4%)
Indiana	$58.86	$36.72	($22.14)	(37.6%)
Kentucky	$58.04	$38.34	($19.71)	(34.0%)
Maryland	$90.14	$49.12	($41.01)	(45.5%)
Michigan	$59.41	$37.93	($21.48)	(36.2%)
New Jersey	$92.31	$48.22	($44.09)	(47.8%)
North Carolina	$81.31	$46.44	($34.86)	(42.9%)
Ohio	$58.27	$36.89	($21.38)	(36.7%)
Pennsylvania	$77.92	$44.69	($33.23)	(42.6%)
Tennessee	$58.49	$38.72	($19.76)	(33.8%)
Virginia	$82.34	$46.52	($35.82)	(43.5%)
West Virginia	$59.94	$39.60	($20.34)	(33.9%)
District of Columbia	$89.84	$47.70	($42.14)	(46.9%)

Components of Day-Ahead, Load-Weighted LMP

Table 2-62 Components of PJM day-ahead, annual, load-weighted, average LMP: January through June 2009 (See 2008 SOM, Table 2-57)

Element	Contribution to LMP	Percent
DEC	$13.69	32.4%
INC	$11.76	27.9%
Coal	$9.54	22.6%
Gas	$3.13	7.4%
Price sensitive demand	$1.62	3.8%
Transaction	$1.06	2.5%
VOM	$0.89	2.1%
SO2	$0.30	0.7%
Oil	$0.27	0.6%
NOx	$0.07	0.2%
Misc	$0.00	0.0%
FMU adder	$0.00	0.0%
Constrained off	($0.00)	(0.0%)
Markup	($0.05)	(0.1%)
NA	($0.07)	(0.2%)
LMP	$42.21	100.0%

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Marginal Losses

Table 2-63 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 through June 2009 (See 2008 SOM, Table 2-67)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.29	$0.06	$0.04
2009	$40.12	$40.04	$0.05	$0.03

Table 2-64 Zonal real-time, simple average LMP components (Dollars per MWh): January through June 2008 and 2009 (See 2008 SOM, Table 2-68)

	2008 (Jan - Jun)				2009 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$84.92	$70.09	$10.85	$3.98	$44.59	$40.04	$2.60	$1.95
AEP	$56.20	$70.09	($11.32)	($2.57)	$36.37	$40.04	($2.38)	($1.28)
AP	$69.61	$70.09	$0.30	($0.78)	$41.77	$40.04	$1.79	($0.05)
BGE	$84.14	$70.09	$11.44	$2.61	$45.22	$40.04	$3.49	$1.69
ComEd	$52.81	$70.09	($13.81)	($3.47)	$30.28	$40.04	($7.26)	($2.50)
DAY	$56.66	$70.09	($11.86)	($1.57)	$35.90	$40.04	($3.22)	($0.92)
DLCO	$52.57	$70.09	($14.31)	($3.21)	$34.49	$40.04	($4.12)	($1.43)
Dominion	$78.58	$70.09	$7.78	$0.70	$43.53	$40.04	$2.90	$0.59
DPL	$81.59	$70.09	$8.29	$3.21	$45.20	$40.04	$3.02	$2.14
JCPL	$86.58	$70.09	$12.25	$4.24	$44.92	$40.04	$2.72	$2.17
Met-Ed	$79.58	$70.09	$7.25	$2.25	$43.73	$40.04	$2.70	$1.00
PECO	$78.86	$70.09	$5.92	$2.86	$43.63	$40.04	$2.19	$1.41
PENELEC	$67.94	$70.09	($1.69)	($0.46)	$40.06	$40.04	$0.09	($0.07)
Pepco	$84.33	$70.09	$12.51	$1.73	$44.77	$40.04	$3.60	$1.13
PPL	$78.47	$70.09	$6.56	$1.82	$43.14	$40.04	$2.29	$0.81
PSEG	$85.48	$70.09	$11.13	$4.26	$45.44	$40.04	$3.17	$2.23
RECO	$84.33	$70.09	$10.36	$3.87	$44.22	$40.04	$2.21	$1.98

Table 2-65 Hub real-time, simple average LMP components (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-69)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.21	$40.04	($3.29)	($2.54)
AEP-DAY Hub	$35.87	$40.04	($2.70)	($1.46)
Chicago Gen Hub	$29.44	$40.04	($7.56)	($3.03)
Chicago Hub	$30.49	$40.04	($7.07)	($2.48)
Dominion Hub	$42.82	$40.04	$2.58	$0.20
Eastern Hub	$45.06	$40.04	$2.71	$2.32
N Illinois Hub	$30.07	$40.04	($7.27)	($2.70)
New Jersey Hub	$45.11	$40.04	$2.94	$2.14
Ohio Hub	$35.84	$40.04	($2.76)	($1.43)
West Interface Hub	$37.20	$40.04	($1.54)	($1.30)
Western Hub	$41.40	$40.04	$1.50	($0.14)

Zonal and PJM Real-Time, Annual, Load-Weighted, Average LMP Components

Table 2-66 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-70)

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$46.77	$41.88	$2.83	$2.06
AEP	$38.30	$42.58	($2.90)	($1.37)
AP	$44.59	$42.73	$1.94	($0.08)
BGE	$48.39	$42.56	$4.01	$1.83
ComEd	$32.25	$41.84	($7.04)	($2.55)
DAY	$37.77	$42.42	($3.74)	($0.92)
DLCO	$35.62	$41.82	($4.68)	($1.52)
Dominion	$46.89	$42.83	$3.43	$0.64
DPL	$48.77	$42.88	$3.54	$2.35
JCPL	$47.50	$42.25	$2.94	$2.31
Met-Ed	$46.64	$42.51	$3.04	$1.09
PECO	$46.05	$42.15	$2.40	$1.50
PENELEC	$42.08	$42.23	($0.06)	($0.09)
Pepco	$47.69	$42.40	$4.10	$1.20
PPL	$46.39	$42.78	$2.69	$0.92
PSEG	$47.42	$41.74	$3.35	$2.33
RECO	$46.29	$41.89	$2.34	$2.07
PJM	$42.48	$42.40	$0.05	$0.03

Table 2-67 PJM day-ahead, simple average LMP components (Dollars per MWh): 2006 through June 2009 (See 2008 SOM, Table 2-71)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$40.01	$40.27	($0.14)	($0.12)

Table 2-68 Zonal day-ahead, simple average LMP components (Dollars per MWh): January through June 2008 and 2009. (See 2008 SOM, Table 2-72)

	2008 (Jan - Jun)				2009 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$83.43	$70.51	$8.01	$4.90	$45.38	$40.27	$2.61	$2.49
AEP	$56.26	$70.51	($10.69)	($3.56)	$36.19	$40.27	($2.41)	($1.67)
AP	$69.57	$70.51	($0.02)	($0.92)	$41.11	$40.27	$0.75	$0.08
BGE	$85.34	$70.51	$11.68	$3.15	$46.01	$40.27	$3.72	$2.02
ComEd	$53.80	$70.51	($12.30)	($4.41)	$30.42	$40.27	($6.40)	($3.45)
DAY	$56.33	$70.51	($11.10)	($3.09)	$35.34	$40.27	($3.37)	($1.57)
DLCO	$54.78	$70.51	($11.83)	($3.91)	$34.04	$40.27	($4.56)	($1.68)
Dominion	$79.34	$70.51	$7.96	$0.87	$44.17	$40.27	$2.93	$0.96
DPL	$82.19	$70.51	$7.83	$3.85	$45.80	$40.27	$2.92	$2.61
JCPL	$87.60	$70.51	$11.02	$6.07	$45.58	$40.27	$2.51	$2.80
Met-Ed	$80.83	$70.51	$7.46	$2.86	$44.24	$40.27	$2.69	$1.28
PECO	$80.54	$70.51	$5.95	$4.08	$44.67	$40.27	$2.43	$1.97
PENELEC	$70.22	$70.51	($0.21)	($0.09)	$40.30	$40.27	($0.01)	$0.04
Pepco	$86.25	$70.51	$13.25	$2.49	$45.60	$40.27	$3.67	$1.66
PPL	$79.68	$70.51	$6.61	$2.56	$43.82	$40.27	$2.46	$1.09
PSEG	$86.08	$70.51	$9.45	$6.12	$46.27	$40.27	$2.99	$3.00
RECO	$84.51	$70.51	$8.50	$5.50	$45.06	$40.27	$2.06	$2.72

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Zonal and PJM Day-Ahead, Annual, Load-Weighted, Average LMP Components

Table 2-69 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-73)

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$48.09	$42.51	$2.90	$2.68
AEP	$37.95	$42.75	($2.99)	($1.81)
AP	$43.83	$43.12	$0.62	$0.08
BGE	$49.12	$42.68	$4.27	$2.17
ComEd	$31.72	$41.65	($6.39)	($3.54)
DAY	$36.99	$42.59	($3.95)	($1.64)
DLCO	$35.10	$41.95	($5.07)	($1.79)
Dominion	$47.39	$42.88	$3.47	$1.04
DPL	$48.86	$42.70	$3.35	$2.81
JCPL	$47.94	$42.27	$2.71	$2.96
Met-Ed	$47.29	$42.79	$3.10	$1.40
PECO	$47.08	$42.32	$2.66	$2.10
PENELEC	$42.35	$42.42	($0.14)	$0.06
Pepco	$48.20	$42.35	$4.07	$1.78
PPL	$46.72	$42.68	$2.83	$1.21
PSEG	$48.45	$42.11	$3.19	$3.16
RECO	$47.59	$42.47	$2.21	$2.91
PJM	$42.21	$42.47	($0.14)	($0.12)

Marginal Loss Accounting

Monthly Marginal Loss Costs

Table 2-70 Marginal loss costs by type (Dollars (Millions)): 2009 (See 2008 SOM, Table 2-74)

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$52.4	($143.8)	$14.2	$210.5	$1.0	($2.6)	($6.8)	($3.2)	$207.3
Feb	$35.9	($88.8)	$8.2	$132.9	($0.3)	($1.2)	($4.2)	($3.2)	$129.7
Mar	$34.9	($78.6)	$8.5	$122.0	($0.8)	($1.3)	($5.3)	($4.8)	$117.2
Apr	$22.2	($59.5)	$5.9	$87.6	($1.3)	($0.1)	($3.7)	($4.9)	$82.6
May	$20.3	($53.6)	$4.6	$78.5	($0.5)	($0.4)	($2.5)	($2.5)	$76.0
Jun	$18.6	($71.2)	$3.1	$92.9	($0.5)	($1.5)	($1.5)	($0.6)	$92.3
Jul	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Aug	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Sep	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Oct	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Nov	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Dec	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$184.2	($495.5)	$44.6	$724.4	($2.4)	($7.1)	($23.9)	($19.2)	$705.2

Zonal Marginal Loss Costs

Table 2-71 Marginal loss costs by control zone and type (Dollars (Millions)): January through June 2009 (See 2008 SOM, Table 2-75)

Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$13.4	$2.7	$0.2	$10.8	$0.3	($0.1)	$0.1	$0.4	$11.3
AEP	($26.4)	($133.1)	$10.0	$116.8	$0.2	($0.3)	($0.9)	($0.3)	$116.5
AP	$2.9	($47.3)	$5.9	$56.1	$1.1	$2.0	($3.1)	($4.0)	$52.1
BGE	$26.9	$5.3	$0.5	$22.1	$1.8	($1.0)	($0.4)	$2.4	$24.5
ComEd	($78.0)	($221.6)	$0.3	$143.9	($0.3)	($1.7)	($0.2)	$1.2	$145.1
DAY	($2.3)	($29.3)	$0.7	$27.6	($0.2)	$1.5	$0.1	($1.5)	$26.1
DLCO	($11.7)	($24.0)	$0.1	$12.5	($1.3)	$0.1	($0.0)	($1.5)	$11.0
Dominion	$42.3	($24.7)	$2.6	$69.6	$1.1	($0.7)	($1.4)	$0.4	$70.0
DPL	$28.2	$4.4	$0.3	$24.1	($1.7)	($0.4)	($0.2)	($1.5)	$22.6
JCPL	$35.2	$12.6	$0.2	$22.9	($0.1)	($1.3)	($0.1)	$1.0	$23.9
Met-Ed	$10.7	$2.8	$0.2	$8.0	($0.1)	($0.3)	($0.1)	$0.1	$8.1
PECO	$31.9	$6.9	$0.0	$25.0	($0.2)	($0.5)	$0.0	$0.3	$25.4
PENELEC	($6.3)	($44.6)	$0.4	$38.8	($0.9)	$1.0	($0.2)	($2.1)	$36.7
Pepco	$40.8	$18.3	$1.4	$23.8	($0.8)	($1.4)	($1.0)	($0.4)	$23.5
PJM	($2.7)	($23.8)	$17.3	$38.4	($0.2)	($6.8)	($13.6)	($7.1)	$31.3
PPL	$23.7	($9.4)	$0.9	$34.0	($0.3)	$0.4	$0.1	($0.6)	$33.3
PSEG	$53.7	$9.4	$3.5	$47.8	($0.6)	$2.4	($2.8)	($5.9)	$41.9
RECO	$2.0	$0.0	$0.1	$2.1	($0.1)	($0.0)	($0.1)	($0.1)	$2.0
Total	$184.2	($495.5)	$44.6	$724.4	($2.4)	($7.1)	($23.9)	($19.2)	$705.2

Table 2-72 Monthly marginal loss costs by control zone (Dollars (Millions)): 2009 (See 2008 SOM, Table 2-76)

Marginal Loss Costs by Control Zone (Millions)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$3.4	$2.0	$1.7	$1.7	$1.2	$1.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$11.3
AEP	$32.6	$22.9	$18.6	$13.1	$11.7	$17.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$116.5
AP	$18.0	$9.4	$8.4	$6.2	$4.8	$5.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$52.1
BGE	$7.0	$4.4	$4.2	$2.6	$2.8	$3.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$24.5
ComEd	$36.3	$26.1	$28.0	$19.4	$16.9	$18.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$145.1
DAY	$7.8	$4.6	$4.5	$3.3	$2.2	$3.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$26.1
DLCO	$3.5	$1.9	$2.1	$1.2	$0.7	$1.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$11.0
Dominion	$20.2	$11.8	$11.1	$7.0	$8.2	$11.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$70.0
DPL	$6.8	$4.3	$4.0	$2.9	$2.4	$2.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$22.6
JCPL	$8.3	$5.6	$3.7	$2.4	$2.1	$1.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$23.9
Met-Ed	$2.4	$1.4	$1.2	$0.9	$0.8	$1.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$8.1
PECO	$8.0	$4.3	$3.5	$2.6	$2.9	$4.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$25.4
PENELEC	$12.1	$5.6	$4.3	$4.1	$5.0	$5.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$36.7
Pepco	$6.0	$3.6	$4.3	$3.1	$2.8	$3.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$23.5
PJM	$14.1	$6.0	$4.8	$2.0	$3.2	$1.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$31.3
PPL	$10.1	$6.5	$5.5	$3.8	$3.0	$4.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$33.3
PSEG	$10.1	$8.8	$7.1	$6.0	$5.1	$4.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$41.9
RECO	$0.6	$0.4	$0.3	$0.3	$0.2	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.0
Total	$207.3	$129.7	$117.2	$82.6	$76.0	$92.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$705.2

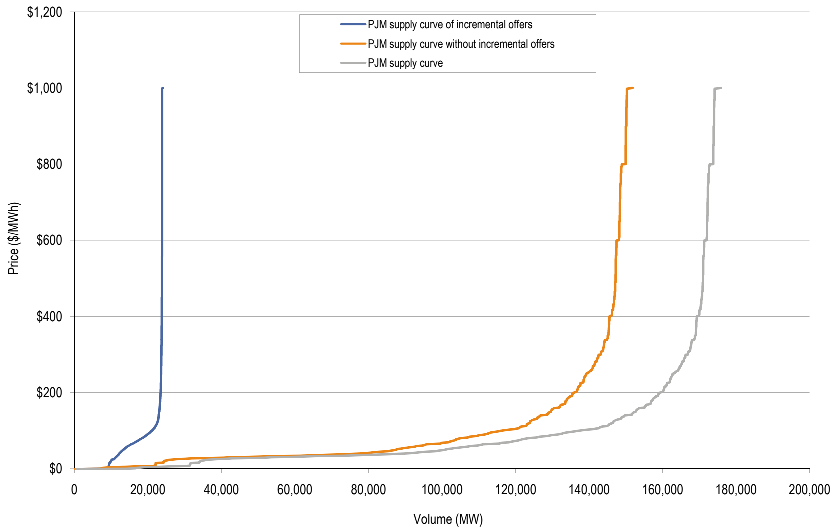
© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Virtual Offers and Bids

Table 2-73 Type of day-ahead marginal units: January through June 2009 (See 2008 SOM, Table 2-77)

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	20.6%	32.2%	33.3%	13.0%	1.0%
Feb	17.4%	38.8%	28.5%	14.6%	0.8%
Mar	14.9%	39.8%	27.6%	17.0%	0.7%
Apr	16.2%	38.7%	28.6%	16.0%	0.5%
May	12.2%	38.5%	29.1%	19.0%	1.2%
Jun	17.3%	30.7%	27.2%	24.0%	0.8%
Annual	16.4%	36.4%	29.1%	17.3%	0.8%

Figure 2-17 PJM day-ahead aggregate supply curves: 2009 example day (See 2008 SOM, Figure 2-16)



Price Convergence

Table 2-74 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-78)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$40.01	$40.12	$0.11	0.3%
Median	$37.46	$35.42	($2.04)	(5.8%)
Standard deviation	$15.38	$19.30	$3.92	20.3%

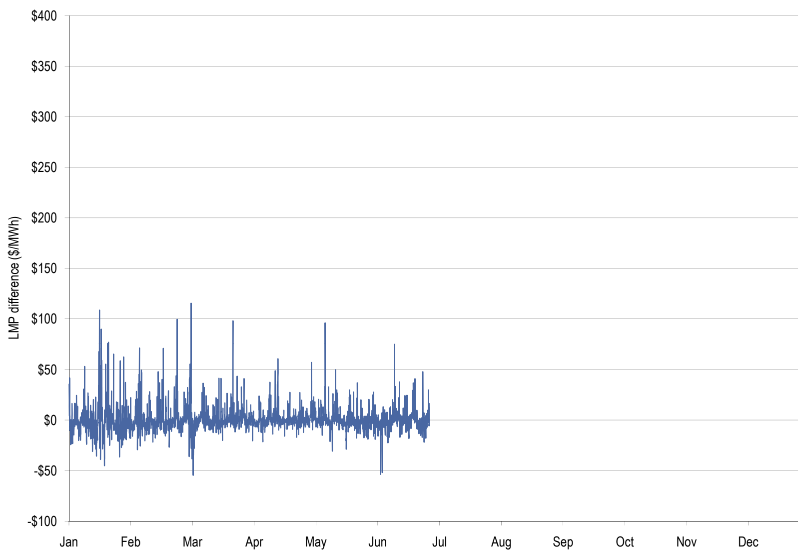
Table 2-75 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 through June 2009 (See 2008 SOM, Table 2-79)

Year	Day Ahead	Real Time	Difference	Difference as Percent Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.0%
2008	$66.12	$66.40	$0.28	0.4%
2009	$40.01	$40.12	$0.11	0.3%

Table 2-76 Frequency distribution by hours of PJM real-time and day-ahead LMP difference (Dollars per MWh): 2005 through June 2009 (See 2008 SOM, Table 2-80)

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.01%	1	0.02%	0	0.00%	1	0.01%	0	0.00%
($100) to ($50)	64	0.74%	9	0.13%	33	0.38%	88	1.01%	3	0.07%
($50) to $0	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%	2,541	58.58%
$0 to $50	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%	1,772	99.38%
$50 to $100	190	99.78%	152	99.77%	255	99.49%	284	99.50%	25	99.95%
$100 to $150	17	99.98%	9	99.87%	31	99.84%	37	99.92%	2	100.00%
$150 to $200	2	100.00%	4	99.92%	5	99.90%	4	99.97%	0	100.00%
$200 to $250	0	100.00%	1	99.93%	1	99.91%	2	99.99%	0	100.00%
$250 to $300	0	100.00%	3	99.97%	3	99.94%	0	99.99%	0	100.00%
$300 to $350	0	100.00%	0	99.97%	2	99.97%	1	100.00%	0	100.00%
$350 to $400	0	100.00%	1	99.98%	1	99.98%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	99.98%	1	99.99%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	1	99.99%	1	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	1	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-18 Hourly real-time minus hourly day-ahead LMP: January through June 2009 (See 2008 SOM, Figure 2-17)



© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Figure 2-19 Monthly average of real-time minus day-ahead LMP: January through June 2009 (See 2008 SOM, Figure 2-18)

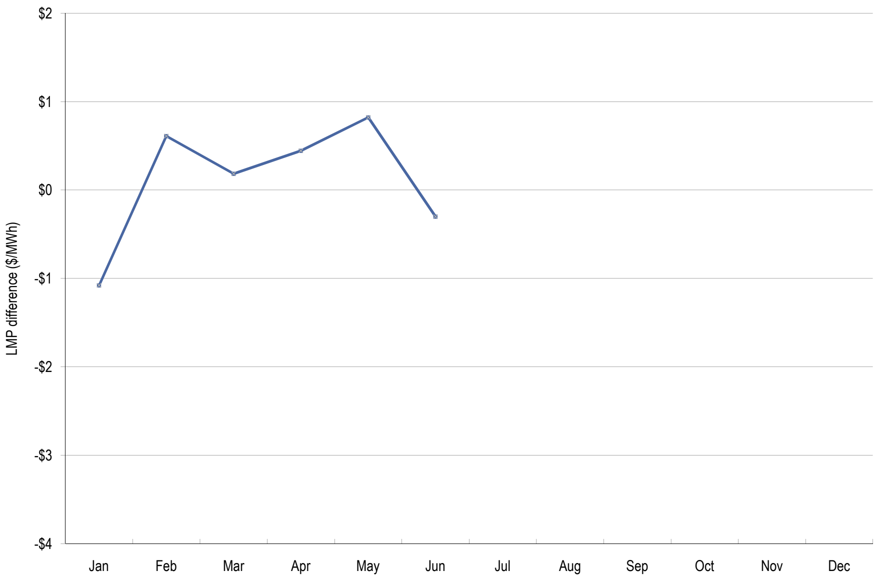
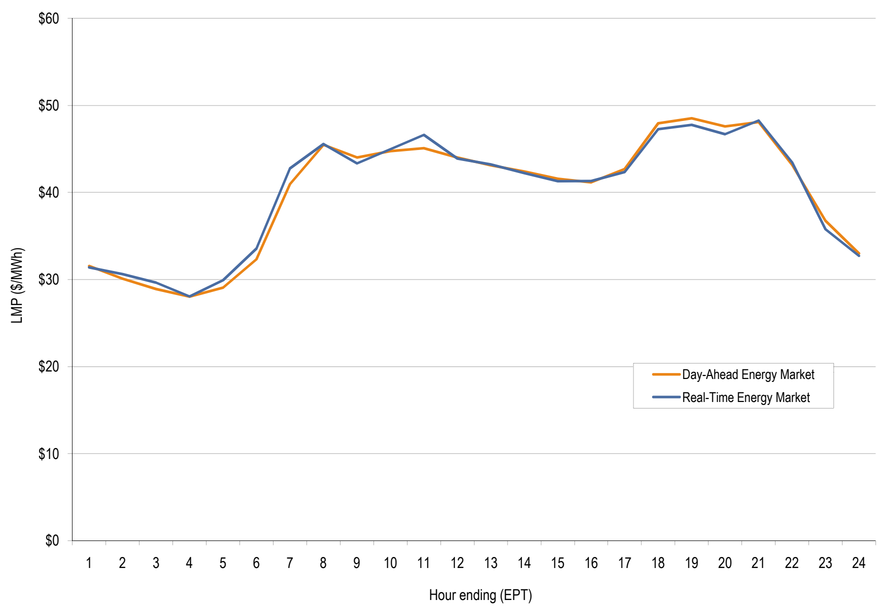


Figure 2-20 PJM system hourly average LMP: January through June 2009 (See 2008 SOM, Figure 2-19)



Zonal Price Convergence

Table 2-77 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-81)

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$45.38	$44.59	($0.78)	(1.8%)
AEP	$36.19	$36.37	$0.18	0.5%
AP	$41.11	$41.77	$0.66	1.6%
BGE	$46.01	$45.22	($0.79)	(1.8%)
ComEd	$30.42	$30.28	($0.14)	(0.5%)
DAY	$35.34	$35.90	$0.56	1.6%
DLCO	$34.04	$34.49	$0.45	1.3%
Dominion	$44.17	$43.53	($0.64)	(1.5%)
DPL	$45.80	$45.20	($0.61)	(1.3%)
JCPL	$45.58	$44.92	($0.66)	(1.5%)
Met-Ed	$44.24	$43.73	($0.51)	(1.2%)
PECO	$44.67	$43.63	($1.04)	(2.4%)
PENELEC	$40.30	$40.06	($0.24)	(0.6%)
Pepco	$45.60	$44.77	($0.83)	(1.9%)
PPL	$43.82	$43.14	($0.68)	(1.6%)
PSEG	$46.27	$45.44	($0.83)	(1.8%)
RECO	$45.06	$44.22	($0.84)	(1.9%)

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Price Convergence by Jurisdiction

Table 2-78 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): January through June 2009 (See 2008 SOM, Table 2-82)

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$45.21	$44.87	($0.34)	(0.8%)
Illinois	$30.42	$30.28	($0.14)	(0.5%)
Indiana	$35.47	$35.71	$0.24	0.7%
Kentucky	$35.95	$36.25	$0.30	0.8%
Maryland	$45.89	$45.20	($0.69)	(1.5%)
Michigan	$36.78	$37.07	$0.29	0.8%
New Jersey	$45.94	$45.16	($0.78)	(1.7%)
North Carolina	$43.03	$42.45	($0.58)	(1.4%)
Ohio	$35.29	$35.69	$0.40	1.1%
Pennsylvania	$42.33	$41.88	($0.45)	(1.1%)
Tennessee	$36.51	$36.34	($0.17)	(0.5%)
Virginia	$43.40	$42.77	($0.63)	(1.5%)
West Virginia	$37.35	$37.62	$0.27	0.7%
District of Columbia	$45.68	$44.92	($0.76)	(1.7%)

Load and Spot Market

Real-Time Load and Spot Market

Table 2-79 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2008 through June 2009 (See 2008 SOM, Table 2-83)

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.3%	17.3%	68.4%	12.6%	15.4%	72.0%	(1.7%)	(1.9%)	3.6%
Feb	15.2%	17.3%	67.5%	13.4%	14.5%	72.1%	(1.7%)	(2.9%)	4.6%
Mar	16.0%	17.1%	66.9%	13.8%	16.7%	69.5%	(2.3%)	(0.4%)	2.6%
Apr	16.6%	18.0%	65.4%	13.5%	17.2%	69.3%	(3.1%)	(0.8%)	3.9%
May	16.0%	18.8%	65.3%	14.6%	18.8%	66.7%	(1.4%)	(0.0%)	1.4%
Jun	13.1%	21.0%	65.9%	12.5%	16.5%	71.0%	(0.6%)	(4.5%)	5.1%
Jul	13.7%	20.6%	65.7%						
Aug	14.9%	22.6%	62.4%						
Sep	14.7%	23.0%	62.2%						
Oct	15.1%	22.7%	62.2%						
Nov	14.8%	22.9%	62.3%						
Dec	12.1%	20.5%	67.4%						
Annual	14.6%	20.1%	65.2%	13.4%	16.4%	70.2%	(1.3%)	(3.7%)	5.0%

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Day-Ahead Load and Spot Market

Table 2-80 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2008 through June 2009 (See 2008 SOM, Table 2-84)

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.2%	15.6%	80.2%	4.4%	13.9%	81.7%	0.2%	(1.7%)	1.5%
Feb	4.5%	16.0%	79.5%	4.5%	12.7%	82.9%	(0.1%)	(3.3%)	3.4%
Mar	4.7%	16.0%	79.3%	4.3%	13.2%	82.5%	(0.4%)	(2.8%)	3.2%
Apr	5.0%	16.8%	78.2%	4.4%	14.1%	81.5%	(0.5%)	(2.7%)	3.3%
May	5.0%	18.2%	76.8%	4.6%	15.9%	79.5%	(0.4%)	(2.3%)	2.7%
Jun	5.5%	20.2%	74.3%	4.7%	14.2%	81.2%	(0.8%)	(6.1%)	6.9%
Jul	5.6%	20.4%	74.0%						
Aug	4.9%	20.2%	75.0%						
Sep	5.4%	19.3%	75.3%						
Oct	5.4%	20.3%	74.3%						
Nov	5.6%	18.9%	75.5%						
Dec	4.6%	19.1%	76.3%						
Annual	5.0%	18.4%	76.5%	4.5%	13.9%	81.6%	(0.5%)	(4.5%)	5.0%

Virtual Markets

Increment Offers and Decrement Bids

Table 2-81 Monthly volume of cleared and submitted INCs, DECs: January through June 2009 (See 2008 SOM, Table 2-85)

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	13,986	21,401	423	621	16,879	26,080	487	670
Feb	13,487	22,228	484	739	15,557	24,967	420	624
Mar	13,364	22,639	552	820	15,186	23,243	459	651
Apr	11,363	19,935	380	645	13,900	21,173	428	607
May	12,853	16,863	388	750	13,973	19,274	529	805
Jun	12,375	15,369	315	750	14,777	18,402	482	802
Jul								
Aug								
Sep								
Oct								
Nov								
Dec								
Annual	12,906	19,719	423	721	15,043	22,169	468	693

Demand-Side Response (DSR)

Emergency Program

Table 2-82 Zonal capability in the Emergency Program for the 2009 peak day through June (By option): January 16, 2009 (See 2008 SOM, Table 2-86)

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	70	20.0	7	8.6
AEP	0	0.0	137	512.5	54	698.5
AP	0	0.0	100	138.9	39	133.7
BGE	0	0.0	196	428.4	46	32.8
ComEd	0	0.0	69	95.6	877	820.9
DAY	0	0.0	23	8.4	8	50.0
DLCO	0	0.0	13	27.0	21	45.6
Dominion	0	0.0	59	5.5	74	81.1
DPL	0	0.0	60	79.3	29	46.0
JCPL	0	0.0	80	97.6	33	14.5
Met-Ed	0	0.0	70	150.7	24	40.8
PECO	0	0.0	146	60.7	154	216.9
PENELEC	0	0.0	38	50.5	35	30.0
Pepco	0	0.0	109	46.8	35	21.3
PPL	0	0.0	114	59.6	97	278.7
PSEG	0	0.0	236	175.3	63	19.9
RECO	0	0.0	3	1.0	21	1.1
Total	0	0.0	1,523	1,957.8	1,617	2,540.4

Table 2-83 Zonal monthly capacity credits: January 1, 2009, through June 30, 2009 (See 2008 SOM, Table 2-87)

Zone	January	February	March	April	May	June
AECO	$154,551	$139,595	$154,551	$149,566	$154,551	$375,086
AEP	$2,578,133	$2,328,636	$2,578,133	$2,494,967	$2,578,133	$3,746,728
APS	$966,835	$873,270	$966,835	$935,647	$966,835	$2,982,596
BGE	$2,882,161	$2,603,243	$2,882,161	$2,789,189	$2,882,161	$4,464,694
ComEd	$3,294,602	$2,975,769	$3,294,602	$3,188,324	$3,294,602	$4,217,299
DAY	$258,904	$233,849	$258,904	$250,552	$258,904	$646,419
DLCO	$258,489	$233,474	$258,489	$250,151	$258,489	$375,138
Dominion	$296,319	$267,643	$296,319	$286,760	$296,319	$1,602,407
DPL	$665,561	$601,152	$665,561	$644,091	$665,561	$971,656
JCPL	$554,279	$500,639	$554,279	$536,399	$554,279	$868,932
Met-Ed	$681,734	$615,760	$681,734	$659,743	$681,734	$1,313,605
PECO	$1,375,581	$1,242,460	$1,375,581	$1,331,207	$1,375,581	$2,052,483
PENELEC	$283,241	$255,831	$283,241	$274,105	$283,241	$1,282,941
Pepco	$572,160	$516,789	$572,160	$553,703	$572,160	$788,433
PPL	$1,200,552	$1,084,370	$1,200,552	$1,161,825	$1,200,552	$3,500,850
PSEG	$922,290	$833,036	$922,290	$892,538	$922,290	$1,720,276
RECO	$10,219	$9,230	$10,219	$9,890	$10,219	$17,897
Total	$16,955,611	$15,314,746	$16,955,611	$16,408,656	$16,955,611	$30,927,439

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Economic Program

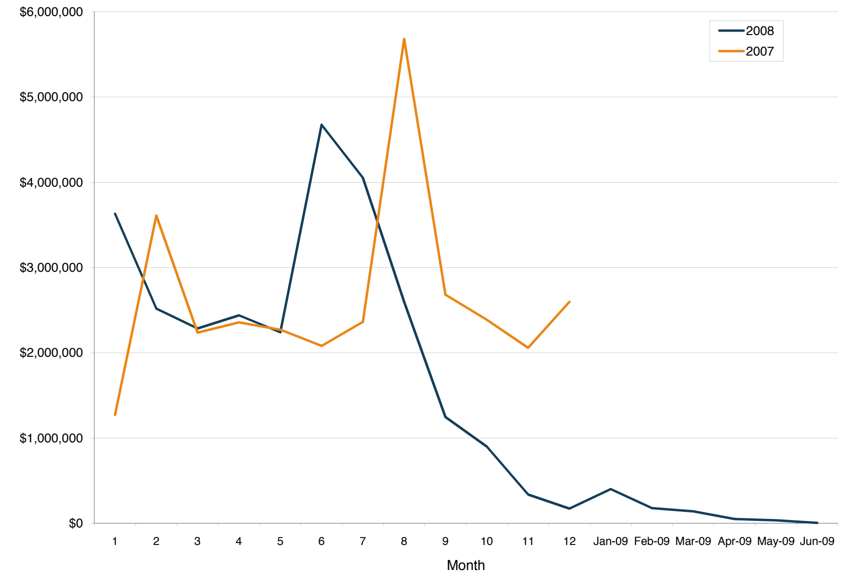
Table 2-84 Economic Program registration on the last day of the month: January 2007 through June 2009[10] (New table)

	2007		2008		2009	
Month	Registered Sites	Registered MW	Registered Sites	Registered MW	Registered Sites	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303
Feb	953	1,567	4,902	2,961	4,869	3,219
Mar	959	1,578	4,972	3,012	4,867	3,227
Apr	980	1,648	5,016	3,197	2,582	3,242
May	996	3,674	5,069	3,588	1,250	2,860
Jun	2,490	2,168	3,112	3,014	1,261	2,455
Jul	2,872	2,459	4,542	3,165		
Aug	2,911	2,582	4,815	3,232		
Sep	4,868	2,915	4,836	3,263		
Oct	4,873	2,880	4,846	3,266		
Nov	4,897	2,948	4,851	3,271		
Dec	4,898	2,944	4,851	3,290		
Avg.	2,684	2,408	4,727	3,185	3,282	3,051

Table 2-85 Zonal capability in the Economic Program: January 16, 2009 (See 2008 SOM, Table 2-89)

	Sites	MW
AECO	32	11.4
AEP	13	251.1
AP	33	228.2
BGE	143	608.1
ComEd	3,849	969.5
DAY	9	10.0
DLCO	27	95.6
Dominion	63	208.9
DPL	114	127.3
JCPL	77	120.3
Met-Ed	41	99.3
PECO	192	222.3
PENELEC	12	23.3
Pepco	16	16.4
PPL	91	225.3
PSEG	148	93.2
RECO	3	0.9
Total	4,863	3,311.0

Figure 2-21 Economic Program Payments: Calendar years 2007 (without incentive payments), 2008 and January through June of 2009[11] (See 2008 SOM, Figure 2-20)



10 The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.

11 All May and June settlement, reduction and credit data are subject to change. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could result in a maximum lag of approximately 74 calendar days. In addition, June data submitted after July 1, 2009 is not reflected due to changes to the PJM DSR settlement collection system and database structure. All MWh reductions and CSP credits have been provided by PJM as the best data available as of July 27, 2009.

Table 2-86 PJM Economic Program by zonal reduction: January through June 2009 (See 2008 SOM, Table 2-92)

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	35	$1,123	89	0	$0	0	4	$117	15	40	$1,241	104
AEP	3,895	$53,692	247	0	$25,038	44	0	$0	0	3,895	$78,730	291
AP	121	$8,079	81	0	$0	0	10	$562	11	131	$8,641	92
BGE	45	$2,193	246	0	$0	0	0	$0	0	45	$2,193	246
ComEd	21	$316	72	0	$0	0	647	$4,351	771	669	$4,667	843
DAY	0	$0	0	0	$0	0	0	$0	0	0	$0	0
DLCO	0	$0	0	0	$0	0	0	$0	0	0	$0	0
Dominion	3,365	$200,005	690	42	$442	76	130	$4,953	109	3,537	$205,400	875
DPL	10	$414	244	0	$0	0	0	$0	0	10	$414	244
JCPL	0	$0	0	0	$0	0	9	$248	30	9	$248	30
Met-Ed	64	$3,218	90	0	$0	0	4	$254	14	68	$3,472	104
PECO	5,125	$122,640	9,968	0	$0	0	204	$13,496	1,053	5,329	$136,136	11,021
PENELEC	154	$6,661	26	0	$0	0	2	$47	6	156	$6,708	32
Pepco	126	$4,224	63	0	$0	0	39	$1,753	71	164	$5,977	134
PPL	6,582	$260,617	2,933	1,895	$65,199	730	172	$14,954	336	8,649	$340,770	3,999
PSEG	62	$1,809	90	0	$0	0	5	$177	32	68	$1,987	122
RECO	1	$12	24	0	$0	0	0	$0	0	1	$12	24
Total	19,606	$665,003	14,863	1,937	$90,679	850	1,227	$40,914	2,448	22,769	$796,596	18,161
Max	6,582	$260,617	9,968	1,895	$65,199	730	647	$14,954	1,053	8,649	$340,770	11,021
Avg	1,153	$39,118	874	114	$5,334	50	72	$2,407	144	1,339	$46,859	1,068

Table 2-87 Settlement days submitted by month in the Economic Program: 2007, 2008 and January through June 2009 (New table)

Month	2007	2008	2009
Jan	887	2,894	1,224
Feb	1,099	2,785	630
Mar	1,185	2,802	542
Apr	1,468	3,386	318
May	1,609	3,309	260
Jun	1,731	3,072	30
Jul	2,421	3,209	
Aug	3,783	3,732	
Sep	3,320	3,179	
Oct	3,446	1,947	
Nov	2,819	1,068	
Dec	2,655	933	
Total	26,423	32,316	2,396

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com

Table 2-88 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007, 2008 and January through June 2009 (New table)

	2007		2008		2009	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	10	68	11	260	13	234
Feb	8	83	10	241	11	128
Mar	8	82	10	216	9	143
Apr	9	92	11	204	5	67
May	10	103	9	227	4	79
Jun	10	163	14	276	1	13
Jul	13	227	14	255		
Aug	15	285	15	270		
Sep	13	280	14	276		
Oct	9	240	10	222		
Nov	8	202	11	205		
Dec	9	241	10	192		
Total Distinct Active	17	384	20	494	13	271

Table 2-89 Hourly frequency distribution of Economic Program MWh reductions and credits: January through June 2009 (See 2008 SOM, Table 2-93)

	MWh Reductions				Program Credits			
Hour	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
1	338	1.48%	338	1.48%	$5,752	0.72%	$5,752	0.72%
2	350	1.54%	689	3.02%	$5,909	0.74%	$11,660	1.46%
3	376	1.65%	1,065	4.68%	$7,064	0.89%	$18,724	2.35%
4	398	1.75%	1,462	6.42%	$7,454	0.94%	$26,178	3.29%
5	404	1.77%	1,866	8.20%	$8,087	1.02%	$34,265	4.30%
6	432	1.90%	2,298	10.09%	$11,313	1.42%	$45,578	5.72%
7	1,408	6.19%	3,707	16.28%	$85,289	10.71%	$130,867	16.43%
8	1,772	7.78%	5,479	24.06%	$102,739	12.90%	$233,606	29.33%
9	1,639	7.20%	7,118	31.26%	$65,834	8.26%	$299,441	37.59%
10	1,227	5.39%	8,345	36.65%	$51,673	6.49%	$351,113	44.08%
11	1,055	4.63%	9,400	41.28%	$45,952	5.77%	$397,065	49.85%
12	980	4.30%	10,379	45.58%	$28,932	3.63%	$425,998	53.48%
13	967	4.25%	11,347	49.83%	$25,788	3.24%	$451,785	56.71%
14	989	4.34%	12,336	54.18%	$25,913	3.25%	$477,699	59.97%
15	950	4.17%	13,286	58.35%	$21,354	2.68%	$499,053	62.65%
16	940	4.13%	14,226	62.48%	$17,649	2.22%	$516,702	64.86%
17	1,055	4.63%	15,282	67.11%	$25,788	3.24%	$542,490	68.10%
18	1,238	5.44%	16,519	72.55%	$46,513	5.84%	$589,003	73.94%
19	1,470	6.46%	17,989	79.01%	$54,571	6.85%	$643,574	80.79%
20	1,502	6.59%	19,491	85.60%	$52,930	6.64%	$696,504	87.43%
21	1,316	5.78%	20,807	91.38%	$58,154	7.30%	$754,658	94.74%
22	848	3.72%	21,655	95.10%	$23,813	2.99%	$778,470	97.72%
23	612	2.69%	22,266	97.79%	$11,193	1.41%	$789,663	99.13%
24	503	2.21%	22,769	100.00%	$6,933	0.87%	$796,596	100.00%

Table 2-90 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 2009 (See 2008 SOM, Table 2-94)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
$0 to $25	122	0.53%	122	0.53%	$5,406	0.68%	$5,406	0.68%
$25 to $50	10,460	45.94%	10,581	46.47%	$146,563	18.40%	$151,969	19.08%
$50 to $75	4,892	21.48%	15,473	67.96%	$125,629	15.77%	$277,597	34.85%
$75 to $100	3,327	14.61%	18,800	82.57%	$152,876	19.19%	$430,474	54.04%
$100 to $125	1,698	7.46%	20,498	90.03%	$108,344	13.60%	$538,817	67.64%
$125 to $150	1,082	4.75%	21,581	94.78%	$92,569	11.62%	$631,386	79.26%
$150 to $200	804	3.53%	22,385	98.31%	$94,528	11.87%	$725,914	91.13%
$200 to $250	318	1.40%	22,702	99.71%	$51,662	6.49%	$777,576	97.61%
$250 to $300	9	0.04%	22,712	99.75%	$2,175	0.27%	$779,751	97.89%
> $300	58	0.25%	22,769	100.00%	$16,845	2.11%	$796,596	100.00%

Load Management (LM)

Table 2-91 Available LM MW by program type: Delivery years 2007 through 2009 (New table)

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,021.1	6,273.8	7,294.9

Table 2-92 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007 through 2012 (New table)

Planning Year	DR Offered in BRA	DR Cleared in BRA
2007/2008	123.5	123.5
2008/2009	691.9	536.2
2009/2010	906.9	856.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.1

© 2009 Monitoring Analytics, LLC www.monitoringanalytics.com